Western Systems Coordinating Council

RELIABILITY CRITERIA

PART I - RELIABILITY CRITERIA FOR TRANSMISSION SYSTEM PLANNING

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DECEMBER 2000

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The WSCC Reliability Criteria set forth the performance standards used by Western Systems Coordinating Council and its Member Systems in assessing the reliability of the interconnected system. During 1996 the Council initiated an in-depth and comprehensive review of these Criteria. Recommendations made as a result of this review have been adopted by the Council and these Criteria have been revised accordingly. Definitions for key words and phrases used in the Council's planning and operating criteria are included.

WESTERN SYSTEMS COORDINATING COUNCIL

RELIABILITY CRITERIA FOR TRANSMISSION SYSTEM PLANNING

PART I

WESTERN SYSTEMS COORDINATING COUNCIL

RELIABILITY CRITERIA FOR TRANSMISSION SYSTEM PLANNING

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WESTERN SYSTEMS COORDINATING COUNCIL

RELIABILITY CRITERIA FOR TRANSMISSION SYSTEM PLANNING

1.0 – INTRODUCTION

The Western Systems Coordinating Council (WSCC) was established to provide a forum for the coordination of planning and operation of the member systems to promote reliability of power supply.

Article VI, Section 1, of the Council Agreement and Bylaws reads, "Subject to the approval of the Board of Trustees, the Planning Coordination Committee shall recommend planning criteria, policies, and procedures for such elements of system planning as affect the reliability of the interconnected bulk power systems and are required to coordinate regional planning, and the Operations Committee shall recommend such operating criteria, policies, and procedures as affect the reliability of operation of the interconnected bulk power systems. The members shall be responsible for meeting the established criteria, policies, and procedures."

In order to accomplish its assignment, the Planning Coordination Committee established the Reliability Subcommittee. This *WSCC Reliability Criteria For Transmission System Planning* document is the result of work by the Subcommittee.

2.0 – PHILOSOPHY OF CRITERIA

Continuity of service to loads is the primary objective of the Council Reliability Criteria. Preservation of interconnected operation during disturbances is secondary to the primary requirement of preservation of service to loads.

Although 100 percent reliability of power supply is impossible, each system will, insofar as practical, protect its customers against loss of service.

However, due to the complexity of the Western Interconnection, it is likely that a disturbance on one system will impact, in varying degrees, other systems in the Western Interconnection. Therefore, the *WSCC Reliability Criteria For Transmission System Planning* sets limits for how a disturbance may impact any system in the Western Interconnection.

Each member of the Council, each Pool or other group of Council members or other entities may have criteria which differ from the criteria presented in this document. Such differences reflect practical considerations such as the geography, type of load being served, system configuration, weather, local acceptance, or political and regulatory oversight. To complement the reliability of the Western Interconnection with the practical needs of each individual system, each individual system may use its internally applied reliability criteria to plan its internal system subject to the following four conditions.

1. The Disturbance-Performance Table on page 11 specifies the allowed effects on the rest of the Western Interconnection for a disturbance originating within a system.

2. For disturbances of the type addressed in the Disturbance-Performance Table; blackouts, voltage collapse, or cascading are not allowed unless the initiating disturbances and corresponding impacts are confined to either a local network or a radial system.

3. Internally applied reliability criteria that differ from the *WSCC Reliability Criteria For Transmission System Planning* may not be imposed on other systems if the differing criteria are more stringent.

4. If an individual system applies reliability criteria to any part of its system that are less stringent than the *WSCC Reliability Criteria For Transmission System Planning,* then other systems are permitted to have the same impact on that individual system.

If an individual system, whose present internally-applied reliability criteria are less stringent than the *WSCC Reliability Criteria For Transmission System Planning*, revises its criteria to require a higher level of performance, and is able to comply with its own revised criteria, then other systems shall also comply with the revised criteria up to the level of performance specified in the *WSCC Reliability Criteria For Transmission System Planning*. Any such criteria revisions should be closely coordinated with affected systems and a reasonable period should be allowed before requiring other systems to meet the revised criteria.

Within the framework of the WSCC, two or more systems may form a group for convenience of planning and operation. Such groups may agree to apply criteria within the group, for internal disturbances, that differ from the *WSCC Reliability Criteria For Transmission System Planning*. This does not relieve any system of its responsibility to apply the *WSCC Reliability Criteria For Transmission System Planning* for disturbances on its system and the resultant effects on other systems outside the group.

Reliability criteria may be defined and measured in terms of the performance of a system under conditions of stress. Prediction of performance requires simulation testing because actual tests cannot be made on systems not yet existing and tests on existing systems may impose unnecessary and unacceptable risks.

It is incumbent upon each system to develop and maintain the network and control data necessary to accurately represent its own system including any embedded systems. The data will include sufficient detail for use in establishing interarea transfer capabilities, establishing operating limits and planning margins to provide both reliability and operating efficiency, designing future system facility additions, and facilitating coordinated planning. Each system will share its system data with the WSCC and individual WSCC members to enable an accurate representation of the Western Interconnection. Applicable WSCC guidelines or procedures for accurate system representation and modeling without built-in margin should be followed.

The *WSCC Reliability Criteria For Transmission System Planning* is based on the understanding that there should be no loss of load on a system for the more common single system element disturbances originating on other systems. There are disturbances that are credible but of low probability for which it is not feasible to protect the Western Interconnection against islanding and/or loss of load. The *WSCC Reliability Criteria For Transmission System Planning* recognizes the necessity for islanding and load shedding for certain disturbances, but such islanding and load shedding should be controlled so as to limit the adverse impact of the disturbance and to leave the Western Interconnection in such condition as to permit rapid load restoration and reestablishment of interconnections. Uncontrolled loss of load is unacceptable even under the most adverse credible disturbance.

Automatic line reclosing is employed by many systems to enhance the reliability of the network. When reclosing is used, the network performance should be tested for unsuccessful reclosure. The *WSCC Reliability Criteria For Transmission System Planning* requires systems to meet the same performance level for unsuccessful reclosing as that required for the initiating disturbance without reclosing.

System additions and changes that affect the reliability of the Western Interconnection will be evaluated in accordance with the *WSCC Reliability Criteria For Transmission System Planning* and results reported to the Council. It is intended that these criteria be periodically reviewed and revised as experience indicates in accordance with the procedures set forth in the *WSCC Reliability Criteria Part V – Process for Developing and Approving WSCC Standards*.

3.0 – CRITERIA FOR PLANNING TRANSMISSION SYSTEM CAPACITY

Article VI, Sections 2 and 3 of the *WSCC Agreement and Bylaws* provide that each member system will inform the Board of Trustees of its plans and operating procedures that may significantly affect the reliability of operation of the Western Interconnection.

Insofar as reliability is concerned, each system should be planned on the basis of adherence to the following principles.

1. Each system should provide sufficient transmission capacity within its system to serve its load and meet its transmission obligation to others without unduly relying on or without imposing an undue degradation of reliability on any other system, unless pursuant to prior agreement with the system(s) so affected.

2. Each system should provide sufficient transmission capacity, by ownership or agreement, for scheduled power transfers between its system and any other system. In transferring such power there should be no undue degradation of reliability on any system not a party to the transfer.

3. Each system should conduct the necessary studies to demonstrate that its power transfers, in the absence of loop flow, will not unduly rely on or impose an undue degradation of reliability on parallel transmission capacity of any other system, except pursuant to prior agreement with the affected system(s).

Each system should plan its system with adequate transfer capability so that its power transfers will not have an undue loop flow impact on other systems, and so that planned schedules do not depend on opposing loop flow to keep actual flows within the path transfer capability. A system adding facilities should recognize that the addition itself could result in a component of loop flow that should be accommodated.

Loop flow is an inherent characteristic of interconnected AC transmission systems and the mere presence of loop flow on circuits other than those of the transfer path is not necessarily an indication of a problem in planning or in scheduling practices.

4. Each system should provide, by ownership or agreement, sufficient reactive capacity and voltage control facilities to satisfy the requirements of its own system without imposing an undue burden upon other systems.

5. When rating transmission facilities, the procedures described in WSCC's *Procedures for Regional Planning Project Review and Rating Transmission Facilities* shall be followed.

6. Each system shall plan for the supply of its reactive requirements, including appropriate reactive reserve margin (VAR margin). Proper control of reactive supply and reactive generation, provision of adequate reactive supply reserve, and maintenance of adequate voltage levels on the transmission system are required to maintain stability limits and reliable system performance.

   - Systems shall plan for coordinated use of voltage control equipment to maintain transmission voltages and reactive flows at sufficient levels to ensure system stability within the operating range of electrical equipment.
   - Systems shall ensure that reactive reserve margins are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserve shall be carried by rotating machinery, static var compensators, and other high speed switching of reactive equipment, which will respond automatically when contingencies occur.

4.0 – CRITERIA FOR TRANSMISSION SYSTEM CONTINGENCY PERFORMANCE

The criteria for transmission system contingency performance are established in terms of the results of simulation tests. There are three main factors which have been considered in defining the criteria. These are Performance Levels, Disturbance Simulation, and The Disturbance-Performance Table which is the heart of the *WSCC Reliability Criteria For Transmission System Planning*.

4.1 – PERFORMANCE LEVELS

The minimum allowable performance levels for interconnected bulk power systems range between a level having no appreciable adverse system effects and a level having substantial effects which may involve load shedding and controlled islanding. The letters A, B, C, and D represent this range of performance.

For Levels A through D, the Criteria do not permit any uncontrolled loss of generation, load, or uncontrolled separation of transmission facilities. For Level E disturbances, uncontrolled loss or separation may occur.

To meet the intent of Level E, a number of extreme contingencies which are judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of category E will be evaluated.

- Level A performance should produce no significant adverse effects outside of the system in which the disturbance occurred, such as -

  Loss of load (Firm or Interruptible) or facility loadings that are outside emergency limits.

- Level B performance anticipates some adverse effects may occur outside of the system in which the disturbance occurred, such as -

  Interruptible load shedding may occur, however, there should be no loss of firm load and facility loadings are to remain within emergency limits.

- Level C performance anticipates substantial adverse effects may occur outside of the system in which the disturbance occurred, such as -

  Firm and interruptible load shedding may occur, however, facility loadings are to remain within emergency limits.

- Level D performance seeks only to prevent cascading and the subsequent blackout of islanded areas. Some additional adverse affects may occur such as -

  Firm and interruptible load shedding or sustained (not growing) oscillations.

- Level E performance seeks only to evaluate for risks and consequences. Additional adverse system impacts may occur such as -

  - Substantial loss of customer demand and generation in a widespread area or areas.
  - Portions or all of the interconnected systems may or may not achieve a new, stable operating point.

  Joint studies with neighboring systems may be required to assess Level E performance. Systems assessing Level E performance shall document measures or procedures necessary to mitigate the impacts of such events. Measures deemed necessary to mitigate or eliminate the risks and consequences of Level E events shall be taken at the discretion of the entities responsible for implementing such measures and shall be reviewed by the WSCC.

Levels C and D presume that some planned and controlled islanding has occurred. This is reflected in the frequency specifications of the Disturbance-Performance Table being below any values that would be anticipated without controlled islanding. Underfrequency load shedding is expected to arrest frequency decline and assure continued operation within the resulting islands.

The *WSCC Reliability Criteria For Transmission System Planning* does not permit any uncontrolled loss of generation, load, or uncontrolled separation of transmission facilities unless the initiating disturbances and corresponding impacts are confined to either a local network or a radial system.

As an example in applying the Disturbance-Performance Table, a disturbance in one system should not cause transient voltage dips in other systems that are greater than 25% for Level A disturbances or 30% for Level B or C disturbances. The duration of the transient voltage dip greater than 20% in other systems should not exceed 20 cycles for Level A or B disturbances or 40 cycles for Level C disturbances. Voltage dips concurrent with faults are not to be considered (see Figure 1 on page 14).

Maximum transient voltage dips and post transient voltage deviations in excess of the numbers presented in the Disturbance-Performance Table can be considered acceptable if they are acceptable to the affected system.

In the application of remedial actions to limit the severity or extent of any foreseeable system disturbance, all systems are expected to cooperate in taking reasonable remedial actions.

4.2 – DISTURBANCE SIMULATION

For simulation test cases, the steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. The principles set forth under Section 3.0 titled "Criteria for Planning Transmission System Capacity" will be given consideration in establishing steady state loading conditions.

Relay action, fault clearing time, and reclosing practice will be represented in simulations according to the planning and operation of the actual or planned systems.

Simulation of post outage conditions will limit actions to automatic devices only and no manual action is to be assumed.

It is recognized that the amount, type, and location of spinning reserve will have an effect on the reliability of the Western Interconnection. It is further recognized that criteria for determining such reserves is the responsibility of the Operations Committee. Information from system studies relating to the importance of the amount, response rate, and location of spinning reserves on interconnected system reliability will be given to the Operations Committee for its use.

4.3 – DISTURBANCE-PERFORMANCE TABLE

The minimum level of performance which is acceptable under simulation tests is presented in the Disturbance-Performance Table. This table defines performance to be expected for a given type of initiating disturbance. The table is based on the planning philosophy that a higher level of performance is required for disturbances generally having a higher frequency of occurrence.

Types of elements lost resulting from various disturbances are listed in the Disturbance-Performance Table in more or less descending order of frequency and increasing order of severity. Performance is specified in discrete levels; A, B, C, D, and E. Hence, to the extent possible, initiating events must be viewed as falling into ranges of frequency such that each range can be associated with a specified performance level. The Disturbance-Performance Table portrays these ranges by giving several examples of disturbances considered to be in each one. The examples presented should provide a basis for estimating performance levels for disturbances that are not in the Disturbance-Performance Table.

When multiple elements are specified, they are assumed to be lost simultaneously. In cases where a prior outage exists on a system, system adjustments will be made to allow the system to meet the required performance specified for the next disturbance. As an example, the loss of a generator with a prior system condition of one generator out should not be considered the simultaneous loss of two generators.

5.0 – PROTECTIVE RELAY SYSTEMS PERFORMANCE

Protective relay systems perform a critical service by detecting and initiating fault clearing thereby protecting the power system from prolonged voltage depression, equipment damage, and transient instability. The design and setting of protective relay systems requires a delicate balance between dependability and security. A relay system needs to be dependable enough to initiate a trip for all faults within its zone of protection and secure enough to avoid initiating trips for faults outside of that zone. If the balance is weighted too heavily toward dependability, improper trips may be initiated and if weighted too heavily in the direction of security the relay system may fail to operate to clear a legitimate fault. When relay systems operate improperly resulting in the unnecessary tripping of power system elements the consequences can be serious. Possible results are loss of load, loss of generation, and cascading outages affecting an extensive portion of the Western Interconnection. This is particularly true when a relay system misoperation causes a multiple contingency outage. Protective relay systems must be designed and maintained to sufficiently high standards that misoperation is of such low likelihood that it can be considered inconsequential. If a relay misoperation occurs during an actual system disturbance resulting in system performance which is less than that required by the Disturbance-Performance Table, then the Criteria have not been met and appropriate corrective action shall be taken.

Protective relay systems have been known to misoperate for numerous reasons including relay hardware failures, communication equipment failures, current reversal, control circuit transients, and improper settings. These misoperations have at times escalated the magnitude of a routine disturbance to a multiple contingency outage resulting in serious system consequences.

When evaluating relay misoperations, the following two conditions must be considered for study:

1) Relay misoperations that have actually occurred resulting in a multiple contingency outage, regardless of the severity of the actual disturbance. This is to allow studying the improper relay operation under stressed system conditions to evaluate the potential for cascading.

2) Relay misoperations that have not occurred but have the potential for initiating a multiple contingency outage that could result in cascading.

If the results of such a study demonstrate cascading, the relay system shall be fully reviewed regarding its likelihood of misoperation. The relay system owner(s) shall submit evidence in a timely fashion, sufficient to demonstrate that misoperation of the relay system is of extremely low likelihood. The documentation submitted shall include information on any improvements that have been made to a relay system that has previously caused a misoperation. The report shall receive a comprehensive evaluation in a timely fashion by a group of WSCC member protective relay engineers. If this evaluation indicates that the future likelihood of misoperation is probable, corrective action must be taken. Until corrective action is taken, performance for the subject multiple contingency must meet the appropriate performance table level for the number of system elements involved in the outage.

6.0 – APPLICATION TO MULTIPLE ELEMENT OUTAGES

When experience proves that an outage involving multiple system elements, AC or DC, occurs more than once during the previous three years (sliding three-year scale) and causes (on another system) loss of load or loss of a thermal unit rated greater than 100 MW, then the intent of the Criteria is not achieved. In such event, the owner(s) of the facilities experiencing the disturbance should take the following actions expeditiously:

1. Implement measures to reduce the frequency of occurrence of the disturbance to meet the Criteria, and/or

2. Take steps to reduce the effects of the disturbance; specifically, the owner(s) should make all reasonable efforts to insure that loss of load or loss of a thermal unit rated greater than 100 MW are confined to their own system(s).

Historical records of all multiple system element outages are to be maintained by the owners of the facilities experiencing the outages regardless of the effects of the outages. This information is to be made available to other WSCC members upon request.

7.0 – APPLICATION TO REMEDIAL ACTION AND SPECIAL CONTROL SCHEMES

Remedial Action Schemes (RAS) are allowed as a way to comply with the *WSCC Reliability Criteria For Transmission System Planning.* If studies show that the RAS failure (i.e., operation when not required or non-operation when required) will result in voltage collapse or cascading, then the RAS failure must be proven to be a non-credible event to the WSCC. Such RAS reliability determinations are made by the WSCC Remedial Action Scheme Reliability Task Force.

If RAS failure occurs, the failure is considered credible until the owners of the facilities have demonstrated that the cause of the failure has been corrected and it is no longer credible.

The Performance Level associated with accidental RAS operation is the more stringent Performance Level of the following: (1) the disturbance that would correctly initiate RAS operation or (2) the action initiated by the RAS. For example, if the RAS is intended to operate for a double-line outage and the remedial action initiated is the tripping of a single generator, then its accidental operation would be required to meet Performance Level A. However, if the RAS is intended to operate for a double-line outage and the remedial action initiated is the tripping of six lines, then its accidental operation would be required to meet Performance Level C.

In general, high-speed control systems, such as used in a DC link, DC line, or a Static Var Control system, are not considered to be RAS. However, they are subject to the reliability philosophies contained in these criteria as is any other proposed or existing facility. If a control malfunction does not directly result in removal from service of the controlled facility, it should not expose other systems to loss of load, generation, or equipment damage or line outages.

8.0 – APPLICATION TO DC LINES

For the purpose of applying the Criteria, monopolar outages shall be treated as one-circuit outages.

A DC line bipole outage is the interruption of both poles of a DC line and neither pole is automatically restarted. During a shakedown period, determined by the owner, a bipolar DC line outage will be treated as a single circuit outage. After the shakedown period, a bipolar DC line outage shall be treated as a one or two-circuit outage depending on the following:

8.1 To qualify for two-circuit outage performance, the owner(s) must show any party which would be adversely affected by a bipole outage that a specific criteria of no more than one bipole outage in three years (0.33 per year) was adopted in the design of the DC system, and

8.2 Two-circuit performance for a bipole outage may be maintained unless actual operating experience shows that two or more bipole outages, that cause (on another system) loss of load, loss of a thermal unit rated greater than 100 MW, or cascading, have occurred in the most recent successive three-year period in which case performance will revert to one-circuit. Two-circuit outage performance will be reinstated when operating experience again shows less than two bipole outages, that cause (on another system) loss of load, loss of a thermal unit rated greater than 100 MW, or cascading, have occurred during the most recent successive three-year period, and

8.3 The owner(s) of a bipolar DC line must demonstrate to any party adversely affected by a DC bipole outage how one-circuit outage performance will be met should it be requested.

February 20, 1969
Revised June 10, 1971
Revised March 9, 1972
Revised March 8, 1983
Revised August 11, 1987
Revised March 9, 1993
Revised December 2, 1994
Revised March 11, 1997
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Revised March 8, 1999

WSCC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECT ON OTHER SYSTEMS[1]

Performance Level(2)	Disturbance(2) Initiated By: No Fault 3 Ø Fault With Normal Clearing SLG Fault With Delayed Clearing DC Disturbance(3)	Transient Voltage Dip Criteria (4)(5)(6)	Minimum Transient Frequency (4)(5)	Post Transient Voltage Deviation (4)(5)(6)(7)	Loading Within Emergency Ratings	Damping
A	Generator One Circuit One Transformer DC Monopole(8)	Max V Dip - 25% Max Duration of V Dip Exceeding 20% - 20 cycles	59.6 Hz Duration of f Below 59.6 Hz - 6 cycles	5%	Yes	>0
B	Bus Section	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 20 cycles	59.4 Hz Duration of f Below 59.4 Hz - 6 cycles	5%	Yes	>0
C	Two Generators Two Circuits DC Bipole (8)	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 40 cycles	59.0 Hz Duration of f Below 59.0 Hz - 6 cycles	10%	Yes	>0
D	Three or more circuits on common ROW		Cascading Is Not Permitted			
E	Loss of multiple 500 kV or higher circuits (3 or more) that cross one another at 1 location Loss of 3 or more circuits that share a common linkage Loss of entire plant with 3 or more generating units Loss of entire substation Loss of multiple circuits, multiple generators, or circuits and generators that have no common mode of failure		Evaluate for risks and consequences			

(1) This table applies equally to either of the following:
   a) A system with all elements in service; or
   b) A system with one element removed and the system adjusted.

(2) Specifies the minimum allowable performance on other systems for a disturbance. Blackouts, voltage collapse, or cascading are not allowed unless the initiating disturbances and corresponding impacts are confined to either a radial system or a local network. The examples of initiating disturbances in this table provide a basis for estimating a performance level to which a disturbance not listed in this table would apply.

(3) Includes disturbances which can initiate a permanent single or double pole DC outage.

(4) Maximum transient voltage dips and duration, minimum transient frequency and duration, and post transient voltage deviations in excess of the values in this table can be considered acceptable if they are acceptable to the affected system or fall within the affected system's internal design criteria. The transient frequency must remain below the indicated frequency for more than six cycles to be considered a violation.

(5) Transient voltage and frequency performance parameters are measured at load buses (including generating unit auxiliary loads), however, the transient voltage dip should not exceed 30% for any bus. Allowable post-transient voltage deviations apply to all buses.

(6) Refer to Figure 1 on page 14.

(7) If it can be demonstrated that post transient voltage deviations that are less than these will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem. Simulation of post transient conditions will limit actions to automatic devices only and no manual action is to be assumed.

(8) Refer to section 8.0 - Application to DC Lines, paragraph 8.2.

TERMS USED IN THE DISTURBANCE-PERFORMANCE TABLE

Bus Section

For the purpose of these criteria, a bus section is considered to be a common point of connection in a substation for two or more system elements. This category is intended to include disturbances such as a faulted substation bus or a faulted line with delayed clearing that could result in the outage of additional system elements. This category is not intended to include outages that involve the failure of a bus tie or bus sectionalizing circuit breaker which results in the outage of two bus sections. The loss of two bus sections is considered a more severe and lower probability disturbance and is covered in the Disturbance-Performance Table under Level E.

Delayed Clearing

Delayed clearing occurs when the primary protection fails to clear the fault and backup relaying is required. Delayed clearing may or may not result in the loss of additional elements depending on the specific protection scheme and the events being studied. Should delayed clearing result in the loss of additional elements, then the level of performance required for that disturbance would be the same as the highest level required for the simultaneous outage of those elements. For example, if delayed clearing would result in the outage of a bus section, then Level B performance would be required.

Entire Plant Including Switchyard

The credible simultaneous loss of an entire plant including the switchyard. The credibility of such loss will depend upon the vulnerability of the plant to common mode failure such as: all machines in the same turbine room, same control room, or same cable shaft or run.

Entire Substation

The credible simultaneous loss of an entire substation or multiple bus sections. This means loss, as a minimum, of several connections to a substation. The extent of the loss would depend on the substation's design and the initiating event and could mean loss of all connections to the substation. Such a loss could be initiated by credible events such as the operation of two overlapping differential relay zones, a bus fault with differential relay failure, or a bus tie breaker failure.

Post Transient Voltage Deviation

In the context of these criteria, post transient voltage deviation refers to "voltage drop" not "voltage rise," and the post transient time frame is considered to be one to three minutes after a system disturbance occurs. This allows available automatic voltage support measures to take place, but does not allow the effects of operator manual actions or Area Generation Control response. The recommended simulation is a post transient power flow that simulates all automatic action but not manual actions and not area interchange control. The post transient voltage deviation criteria do not fully identify all potential voltage collapse problems. Voltage collapse criteria should address additional local constraints like voltage, reactive, and power transfer margins.

<u>Three or More Circuits in a Right-of-Way</u>

In the application of the Disturbance-Performance Table, this category is intended to cover those situations where the separation between circuits is such that a common mode failure could result in the simultaneous outage of multiple circuits. The credibility of such an outage depends on the credibility of the common mode failure. Considerations in the determination of credibility should include line design; length; location, whether forested, agricultural, mountainous, etc.; outage history; operational guidelines; and separation between circuits. For example, some organizations use separation by more than the span length as adequate to designate the circuits as being in separate corridors.

<u>Two Circuits</u>

In the application of the Disturbance-Performance Table, this category is intended to cover those situations where a common mode failure could result in the simultaneous loss of two circuits. The credibility of such an outage depends upon the credibility of the common mode failure. The credible outage of two circuits could result from a lightning storm or forest fire. Loss of two circuits does not require the same tower or right-of-way to be credible. Considerations in the determination of credibility should include line design; length; location, whether forested, agricultural, mountainous, etc.; outage history; operational guidelines; and separation between circuits. Common mode failures of substation terminal equipment, such as a breaker failure, are covered under the Bus Section category in the Disturbance-Performance Table.

<u>Two Generator Units</u>

The simultaneous loss of any two generating units connected to the same switchyard must meet Level C performance of the Criteria.

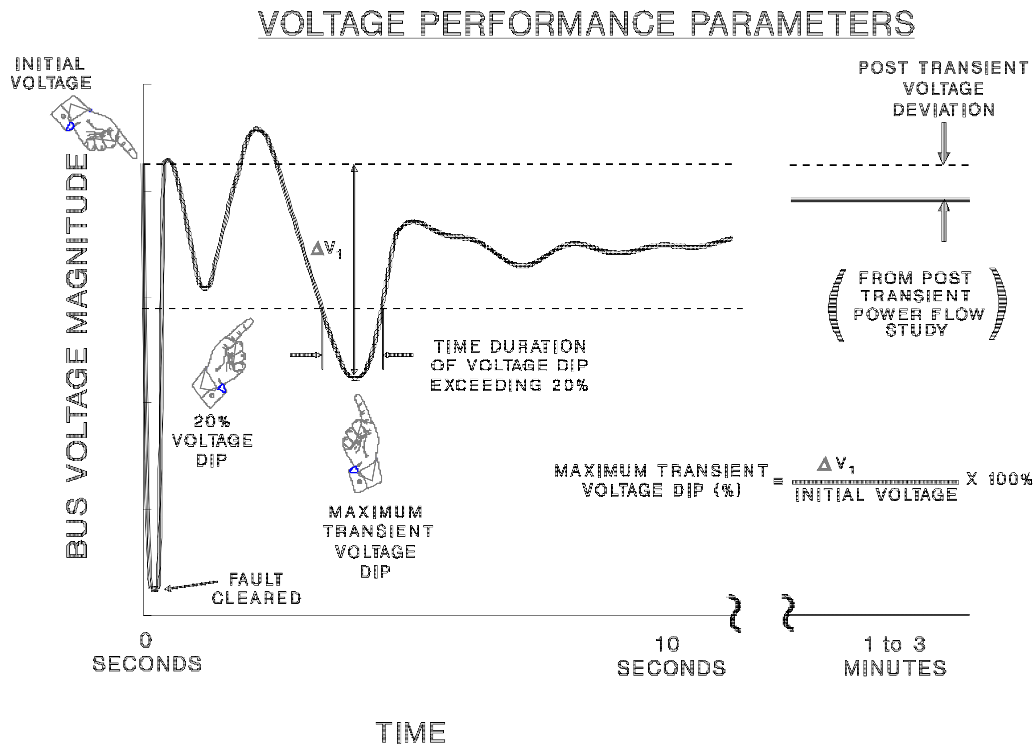
VOLTAGE PERFORMANCE PARAMETERS
INITIAL VOLTAGE
POST TRANSIENT VOLTAGE DEVIATION
BUS VOLTAGE MAGNITUDE
ΔV1
FROM POST TRANSIENT POWER FLOW STUDY
TIME DURATION OF VOLTAGE DIP EXCEEDING 20%
20% VOLTAGE DIP
MAXIMUM TRANSIENT VOLTAGE DIP (%) = ΔV1 / INITIAL VOLTAGE X 100%
MAXIMUM TRANSIENT VOLTAGE DIP
FAULT CLEARED
0 SECONDS
10 SECONDS
1 to 3 MINUTES
TIME

Figure 1

WESTERN SYSTEMS COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

PART II

WESTERN SYSTEMS COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

INTRODUCTION

The Western Systems Coordinating Council was established to promote the reliable operation of the interconnected bulk power system by the coordination of planning and operation of generating and interconnected transmission facilities.

The Planning Coordination Committee assigned the Reliability Subcommittee the task of developing an Adequacy of Supply Assessment Methodology. This document establishes the policy for conducting power supply assessments using the methodology developed by the Reliability Subcommittee. This policy shall be periodically reviewed and revised as experience indicates.

PURPOSE OF POWER SUPPLY ASSESSMENT

To ensure the reliability of the interconnected bulk electric system, it is necessary to assess both the security and the adequacy of the overall Western Interconnection. This document is focused on the portion of the assessment dealing with the adequacy of power supply. As electric industry restructuring has begun to break apart the traditional model of the vertically integrated utility, the responsibility for maintaining the adequacy of the power supply is moving toward market mechanisms. Though there may not be specific entities entrusted to plan for adequate resources, there exists a need to assess whether projected resources will be sufficient to reliably meet demand. Such information will allow regulators and policy makers to anticipate potential shortfalls so that determinations can be made as to whether impediments or insufficient incentives exist in the market.

It is not the intent of an adequacy assessment to replace the market, create sanctionable criteria or anticipate future energy prices. Its purpose is to project whether enough resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths. Such an assessment is required to comply with the NERC Planning Standards. These standards require that each region perform a regional assessment of existing and planned (forecast) adequacy of the bulk electric system.

It is recognized that it is impossible to provide 100% adequacy of power supply. It is the purpose of this document to establish a uniform policy for assessing the adequacy of installed and planned resources within the WSCC region for the purposes of reporting within the Council, and to outside agencies. The assessments shall cover a period encompassing the next 5 years.

ASSESSMENT METHODOLOGY

The Power Supply Assessment Methodology shall be developed and maintained by the Reliability Subcommittee. Adequacy of supply may be defined and measured in terms of generating reserve margins and transmission limitations between load and resource areas and/or based on probabilistic methods. Appropriate technical tools shall be developed and utilized in conducting the assessments. The assessments shall account for diversity of load and generation, and account for transmission constraints between load and resource areas.

DATA REQUIREMENTS

To aid WSCC in assessing resource adequacy, the following information shall be provided by the WSCC member systems:

Load Forecasts

- Electricity demand and energy forecasts, including uncertainties
  - Variations due to weather
  - Variations due to other factors affecting forecasts

Demand Side Management (DSM) Programs

- Existing and planned demand-side management programs
  - Direct controlled interruptible loads
  - Aggregate effects of multiple DSM programs

Resource Information

- Supply-side resource characteristics, including uncertainties
  - Consistent generator unit ratings, including seasonal variations and environmental considerations affecting hydro and thermal units
  - Availability of generating units
  - Fuel type

Transmission Information

- Capabilities, availability of transmission capacity, and other uncertainties

REPORTING OF POWER SUPPLY ADEQUACY

The assessment of generating reserve margins and transmission limitations between load and resource areas as well as probabilities of supplying expected load levels, accounting for uncertainties, shall be developed and the results reported on a seasonal basis. The assessment shall be consistent with the requirement for maintaining operating reserves as defined in the *WSCC Minimum Operating Reliability Criteria* and NERC Operating Policies.

Approved by Reliability Subcommittee June 16, 2000
Approved by Planning Coordination Committee June 30, 2000
Approved by Board of Trustees August 8, 2000

WESTERN SYSTEMS COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

PART III

WESTERN SYSTEMS COORDINATING COUNCIL

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WESTERN SYSTEMS COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

INTRODUCTION

The reliable operation of the Western Interconnection requires that all entities comply with the *Western Systems Coordinating Council (WSCC) Minimum Operating Reliability Criteria* (hereafter referred to as MORC). The MORC shall apply to system operation under all conditions, even when facilities required for secure and reliable operation have been delayed or forced out of service.

On a continuing basis, the North American Electric Reliability Council (NERC), through its Operating Committee, establishes, reviews, and updates operating criteria to be followed by individual entities, pools, coordinated areas and reliability councils. All entities, WSCC members and nonmembers, shall operate in accordance with the NERC or WSCC Reliability Criteria, whichever is more specific or stringent. In addition to complying with the MORC, all entities shall comply with all WSCC Operating Policies and Procedures which are included in the *WSCC Operations Committee Handbook*. The WSCC shall periodically review and revise MORC in accordance with the guidelines set forth in the *WSCC Reliability Criteria Part V – Process for Developing and Approving WSCC Standards*.

NERC has identified control areas as the primary entities responsible for ensuring the secure and reliable operation of the interconnected power system. Secure and reliable operation can only result from all entities complying with a consistent set of operating criteria. To this end it is imperative for all control areas in the Western Interconnection to be members of the WSCC.

Entities such as Independent System Operators and Area Security Coordinators may assume some of the responsibilities that control areas have traditionally held. It is also imperative that these entities be WSCC members and comply with all operating reliability criteria which apply to control areas.

The MORC and all WSCC Operating Policies and Procedures apply to all entities unless expressly stated as applying only to a particular entity. It is imperative that all entities equitably share the various responsibilities to maintain reliability. Examples of equitably sharing reliability responsibilities include, but are not limited to:

- proper coordination and communication of interchange schedules,
- participation in coordinated underfrequency load shedding programs,
- participation in the unscheduled flow mitigation plan,
- providing appropriate levels of power system stabilizers, and
- maintaining appropriate governor droop settings.

Section 1 - Generation Control and Performance

All generation shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action will be taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

A. Operating Reserve

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- supply requirements for load variations.
- replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
- meet on-demand obligations.
- replace energy lost due to curtailment of interruptible imports.

1. **Minimum operating reserve.** Each control area shall maintain minimum operating reserve which is the sum of the following:

    (a) **Regulating reserve.** Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's *Control Performance Criteria.*

    Plus (b) **Contingency reserve.** An amount of spinning and nonspinning reserve, sufficient to meet the Disturbance Control Standard as defined in 1.E.2(a). This Contingency Reserve shall be at least the greater of:

    (1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or

    (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve).

    For generation-based reserves, only the amount of unloaded generating capacity that can be loaded within ten minutes of notification can be considered as reserve.

    Plus (c) **Additional reserve for interruptible imports.** An amount of reserve, which can be made effective within ten minutes following notification, equal to interruptible imports.

    Plus (d) **Additional reserve for on-demand obligations.** An amount of reserve, which can be made effective within ten minutes following notification, equal to on-demand obligations to other entities or control areas.

2. **Acceptable types of nonspinning reserve.** The nonspinning reserve obligations identified in A.1.b, A.1.c, and A.1.d, if any, can be met by use of the following:

   (a) interruptible load

   (b) interruptible exports

   (c) on-demand rights from other entities or control areas

   (d) spinning reserve in excess of requirements in A.1.a and A.1.b

   (e) off-line generation which qualifies as nonspinning reserve (see definition)

3. **Knowledge of operating reserve.** Operating reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.

4. **Restoration of operating reserve.** After the occurrence of any event necessitating the use of operating reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes.

5. **Analysis of islanding potential.** Each entity or coordinated group of entities shall analyze its potential for islanding in total or in part from interconnected resources at least every three years and shall maintain appropriate additional operating reserve for such contingencies or, if such is impractical, its load and generation shall be balanced by other appropriate measures.

6. **Sharing operating reserves.** Under written agreement, the operating reserve requirements of two or more control areas may be combined or shared, providing that such combination, considered as a single control area, meets the obligations of paragraph A.1. Similarly, arrangements may be made whereby one control area supplies a portion of another's operating reserve, provided that such capacity can be made available in such a manner that both meet the requirements of paragraph A.1. A firm transmission path must be available and reserved for the transmission of these operating reserves from the control area supplying the reserves to the control area calling on them.

7. **Operating reserve distribution.** Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements. Spinning reserve should be distributed to maximize the effectiveness of governor action.

8. **Review of contingencies.** To determine the amount of operating reserve required, contingencies shall be frequently reviewed and the most severe contingency designated.

B. Automatic Generation Control

Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load. It shall also provide its proper contribution to Interconnection frequency regulation.

1. **Inclusion in control area.** Each entity operating transmission, generation, or distribution facilities shall either operate a control area or make arrangements to be included in a control area operated by another entity. All generation, transmission, and load operating within the Western Interconnection shall be included within the metered boundaries of a WSCC control area. Control areas are ultimately responsible for ensuring that the total generation is properly matched to total load in the Interconnection.

2. **AGC.** Prudent operating judgment shall be exercised in distributing control among generating units. AGC shall remain in operation as much of the time as possible. As described in the *WSCC Guidelines for Suspending Automatic Generation Control* in the *WSCC Operations Committee Handbook*, AGC suspension should be considered when AGC equipment has failed or if system conditions could be worsened by AGC.

3. **Familiarity with AGC equipment.** Control center operating personnel must be thoroughly familiar with AGC equipment and be trained to take necessary corrective action when equipment fails or misoperates. If primary AGC has become inoperative, backup AGC or manual control shall be used to adjust generation to maintain schedules.

4. **Data scan rates for ACE**. It is recommended that the periodicity of data acquisition for and calculation of ACE should be no greater than four seconds.

C. Frequency Response and Bias

1. **Frequency bias setting.** The frequency bias shall be set as close as possible to the control area's natural frequency response characteristic. In no case shall the annual frequency bias or the monthly average frequency bias be set at a value of less than 1% of the estimated control area annual peak load per 0.1 Hz change in frequency.

2. **Governors.** To provide an equitable and coordinated system response to load/generation imbalances, governor droop shall be set at 5%. Governors shall not be operated with excessive deadbands, and governors shall not be blocked unless required by regulatory mandates.

3. **Tie-line bias.** Each control area shall operate its AGC on tie-line frequency bias mode, unless such operation is adverse to system or Interconnection reliability.

D. Time Control

1. **Time error.** Control areas shall assist in maintaining frequency at or as near 60.0 Hz as possible and shall cooperate in making any necessary time corrections per the *WSCC Procedure for Time Error Control*. The amount of

continuous time error contribution is a function of control area time error bias, inadvertent interchange accumulation, and the time error.

2. **Maintain standards for frequency offset.** Control areas shall cooperate in maintaining standards established by the NERC Operating Committee for frequency offset to make time corrections manually.

3. **Time error correction notice and commencement.** Time error corrections shall start and end on the hour or half hour, and notice shall be given at least twenty minutes before the time error correction is to start or stop. Time error corrections shall be made at the same rate by all control areas.

4. **Calibration of time and frequency devices.** Each control area shall at least annually check and calibrate its time error and frequency devices against a common reference.

E. Control Performance

1. **Continuous monitoring.** Each control area shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.

   (a) **Control performance standard (CPS1).** Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β (β is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ε, is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee.

   (b) **Control performance standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See NERC's *Performance Standard Training Document*, Section B.1.1.2 for the methods for calculating L_{10}.

   (c) **Control performance standard (CPS) compliance.** Each control area shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90%.

2. **Disturbance conditions.** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions (see the *Performance Standard Training Document*, Section B.2):

   (a) **Disturbance Control Standard.** Following the start of a disturbance, the ACE must return either to zero or to its pre-disturbance level within the time specified in the Disturbance Control Standard currently in effect in NERC Policy 1.

   (b) **Disturbance control standard compliance.** Each control area or reserve sharing group shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances.

(c) **Reportable disturbance reporting threshold.** Each control area or reserve sharing group shall include events that cause its Area Control Error (ACE) to change by at least 35% of the maximum loss generation that would result from a single contingency.

(d) **Average percent recovery.** For each reportable disturbance, the control area(s) with a MW loss or participating in the response, such as through operating reserve obligations or through a reserve sharing group, shall calculate an Average Percent Recovery. A copy of the control area's calculations, ACE chart, and Net Tie Deviation from Schedule chart shall be submitted to the NERC Regional Performance Subcommittee representative not later than 10 calendar days after the reportable disturbance.

(e) **Contingency reserve adjustment factor.** The WSCC Performance Work Group (PWG) shall determine the Contingency Reserve Adjustment Factor for each control area no later than April 20, July 20, September 20, and January 20 for the previous quarter. The local PWG representatives shall allocate the factor among control areas that are members of reserve sharing groups according to the allocation methods developed by the group.

(f) **Operating reserve for control areas and reserve sharing groups.** Minimum Operating Reserve shall be increased by the Contingency Reserve Adjustment Factor. The WSCC Performance Work Group shall monitor the compliance of each control area and reserve sharing group for carrying the minimum required operating reserve.

3. **ACE values.** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

F. Inadvertent Interchange

1. **Hourly verification.** Each control area shall, through hourly schedule verification and the use of reliable metering equipment, accurately account for inadvertent interchange.

2. **Common metering.** Each control area interconnection point shall be equipped with a common kWh meter, with readings provided hourly at the control centers of both areas.

3. **Including all interconnections.** All interconnections shall be included in inadvertent interchange accounting. Interchange served through jointly owned facilities and interchange with borderline customers shall be properly taken into account.

G. Control Surveys

1. **Survey purpose.** Periodic surveys of the control performance of the control areas shall be conducted. These surveys reveal control equipment

malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

2. **Surveys.** The control areas in the Western Interconnection shall perform each of the following surveys, as described in the *NERC Control Performance Criteria Training Document*, when called for by the NERC Performance Subcommittee:

   (a) **AIE survey.** Area Interchange Error survey to determine the control area's interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

   (b) **FRC survey.** Area Frequency Response Characteristic survey to determine the control area's response to changes in system frequency.

   (c) **CPC survey.** Control Performance Criteria survey to monitor the control area's control performance during normal and disturbance situations.

H. Control and Monitoring Equipment

1. **Tie line bias control equipment.** Each control area shall use accurate and reliable automatic tie line bias control equipment as a means of continuously balancing actual net interchange with scheduled net interchange, plus or minus its frequency bias obligation and automatic time error correction. The power flow and ACE signals that are transmitted for regulation service shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.

2. **Tie flows in ACE calculation.** To achieve accurate control, each control area shall include all of its interconnecting ties in its ACE calculation. Common interchange metering equipment at agreed upon terminals shall be used by adjacent control areas.

3. **Control checks made each hour.** Actual interchange shall be verified each hour by each control area using tie line kWh meters to determine regulating performance. Adjacent control areas shall use the same MWh value for each common interchange point. Control settings shall be adjusted to compensate for any equipment error until equipment malfunction can be corrected.

I. Backup Power Supply

Under emergency conditions, adequate and reliable emergency or backup power supply must be available to provide for generating equipment protection and continuous operation of those facilities required for restoration of the system to normal operation.

1. **Safe shut-down power.** Emergency or auxiliary power supply shall be provided for the safe shutdown of thermal generating units when completely isolated from a power source.

2. **Reliable start-up power.** A reliable and adequate source of start-up power for generating units shall be provided. Where sources are remote from the generating unit, standing instructions shall be issued to expedite start up.

3. **Black start capability for critical generating units.** All control areas must identify critical generating units and ensure provision of "black start" capability for these units if appropriate arrangements have not been made to receive off-system power for the purpose of system restoration.

4. **Testing.** Emergency or backup power supplies shall be periodically tested to ensure their availability and performance.

Section 2 - Transmission

A. Transmission Operations

1. **Basic criteria.** The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood (as defined below). Entities must ensure this criteria is met under all system conditions including equipment out of service, equipment derates or modifications, unusual loads and resource patterns, and abnormal power flow conditions. A single contingency means the loss of a single system element, however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood. When experience proves that an outage involving multiple system elements, AC or DC, occurs more than once during the previous three years and causes, on other systems, loss of load, loss of generation rated greater than 100 MW or cascading outages, it shall be treated as a single contingency.

   When it is agreed that a disturbance on specific facilities occurs more often than should be reasonably expected and results in an undue burden on the transmission system, the owners of the facilities shall take measures to reduce the frequency of occurrence of the disturbance, and cooperate with other entities in taking measures to reduce the effects of such disturbance.

   Continuity of service to load is the primary objective of the *Minimum Operating Reliability Criteria*. Preservation of interconnections during disturbances is a secondary objective except when preservation of interconnections will minimize the magnitude of load interruption or will expedite restoration of service to load.

   It is undesirable for the loss of load to exceed the amount of load designed to be tripped. This applies to all levels of system underfrequency load shedding programs, undervoltage load tripping schemes or other controlled remedial actions. It applies whether the initiating disturbance occurs within or outside the affected system. Entities may be required to establish maximum import levels to meet these criteria. The necessary operating procedures, equipment, and remedial action schemes shall be in place to prevent unplanned or uncontrolled loss of load or total system shutdown.

2. **Joint reliability procedures.** Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3. **Phase-shifting transformers and other flow altering facilities.** Phase shifting transformers or other facilities, when used to alter power flow through the interconnected power system, shall be operated to control the actual power flow within the limits of the scheduled power flow and the unaltered power flow. In meeting the criteria, a tolerance of two taps on phase shifting transformers and one discrete increment on other noncontinuous controllable devices is permissible provided no other operating criteria are violated. Such power flow altering facilities may be operated to some other criteria provided agreement is reached among the affected parties.

4. **Protective relay reliability.** Relays that have misoperated or are suspected of improper operation shall be promptly removed from service until repaired or correct operation is verified.

B. Voltage and Reactive Control

1. **Maintaining service.** To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled, adequate reactive reserves shall be provided, and adequate transmission system voltages shall be maintained.

2. **Providing reactive requirements.** Each entity shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

3. **Coordination.** Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4. **Transmission lines.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly make notification according to the *WSCC Procedure for Coordination of Scheduled Outages and Notification of Forced Outages*~~,~~ when removing such facilities from and returning them back to service.

5. **Generators.** Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the host control area. The control mode of generating units shall be accurately represented in operating studies.

6. **Automatic voltage control equipment.** Automatic voltage control equipment on generating units, synchronous condensers, and static var compensators shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the host control area operator.

7. **Power system stabilizers.** Power system stabilizers on generators and synchronous condensers shall be kept in service as much of the time as possible.

8. **Reactive reserves.** Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

9. **Undervoltage load shedding.** Operating entities shall assess the need for and install undervoltage load shedding as required to augment other reactive reserves to protect against voltage collapse and ensure system reliability performance criteria as specified in the WSCC Disturbance-Performance Table of Allowable Effect on Other Systems are met during all internal and external outage conditions. The operator shall have written authority to manually shed additional load if necessary to maintain acceptable voltages and/or sufficient reactive margin to protect against voltage collapse.

10. **Switchable devices.** Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

11. **HVDC.** Entities with HVDC transmission facilities should use the reactive capabilities of converter terminal equipment for voltage control.

Section 3 - Interchange

To ensure the secure and reliable operation of the interconnected power system, all entities involved in interchange scheduling shall coordinate and communicate information concerning schedules and schedule changes accurately and timely as detailed in the *WSCC Scheduling Procedures for All Entities Involved in Interchange Scheduling*.

A. Interchange

1. **Net schedules.** The net schedule on any control area to control area interconnection or transfer path within a control area shall not exceed the total transfer capability of the transmission facilities.

2. **Transfer capability.** Transmission providers or control areas shall determine normal total transfer capability limits for the delivery and receipt of scheduled interchange. The determination of such total transfer capability limits shall, as far as practicable, take into consideration the effect of power flows through

other parallel systems or control areas under both normal operating conditions and with a single contingency outage of the most critical facility.

3. **Schedule confirmation and implementation.** All scheduled transactions shall be confirmed and implemented between or among the control areas involved in such transactions. “Control areas involved” means the control area where the schedule originates, the control area(s) providing transmission service for the transaction, and the control area where the scheduled energy is delivered. If a schedule cannot be confirmed it shall not be implemented.

4. **Schedule verification.** Control areas shall verify the net scheduled interchange with adjacent control areas on a preschedule and hourly real-time basis. Such real-time verification shall take place prior to the start of the ramp.

5. **Schedule changes.** Schedule changes must be coordinated between control areas to ensure that the schedule changes will be executed by all control areas at the same time, in the same amount and at the same rate.

6. **Type of transaction.** Parties providing and receiving the scheduled energy shall agree upon the type of transaction being implemented (firm or interruptible) and the control area(s) and other parties providing the operating reserve for the transaction, and shall make this information available to all control areas involved in the transaction.

7. **Information sharing.** Control areas, pools, coordinated areas or reliability councils shall develop procedures to disseminate information on schedules which may have an adverse effect on other control areas not involved in making the scheduled power transfer.

8. **Unscheduled flow.** Unscheduled flow is an inherent characteristic of interconnected AC power systems and the mere presence of unscheduled flow on circuits other than those of the scheduled transmission path is not necessarily an indication of a problem in planning or in scheduling practices. WSCC transmission paths experiencing significant curtailments as a result of unscheduled flow may be qualified for unscheduled flow relief under the *WSCC Unscheduled Flow Reduction Procedure*. All personnel involved in interchange scheduling shall be trained and fully competent in implementing the *WSCC Unscheduled Flow Reduction Procedure*.

   The WSCC planning process and the *Unscheduled Flow Reduction Procedure* are designed to minimize impact of unscheduled flow for normal system configurations. During abnormal system configurations such as during the restoration period following a major system disturbance, consideration shall be given to the unscheduled flow effects created by schedules and scheduled transmission paths and the security coordinator(s) shall ensure that all schedules are arranged such that the effect of unscheduled flow does not cause transfer capability limits to be exceeded on other transmission paths.

   It is unacceptable to rely on opposing unscheduled flow to keep actual flows within the path total transfer capability regardless of whether the path is a transmission element internal to a control area or whether the path is a control area to control area interconnection.

B. Transfer Capability Limit Criteria

The total transfer capability limit is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- An interconnection from one control area to another control area; or
- A transfer path within a control area.

The net schedule and prevailing actual power flowing over an interconnection or transfer path within a control area shall not exceed the total transfer capability limit on the interconnection or transfer path.

1. **Operating limits.** No elements within the interconnection shall be scheduled above continuous operating limits. An element is defined as any generating unit, transmission line, transformer, bus, or piece of electrical equipment involved in the transfer of power within an interconnection. At all times the interconnected system shall be operated so neither the net scheduled or actual power transferred over an interconnection or transfer path shall exceed the total transfer capability of that interconnection or transfer path. If the limit is exceeded, immediate action shall be taken to reduce actual flow to within transfer capability limits within 10 minutes for stability limitations and within 30 minutes for thermal limitations.

2. **Stability.** The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the *WSCC Reliability Criteria for Transmission System Planning*. If a single event could cause loss of multiple elements, these shall be considered in lieu of a single element outage. This could occur in exceptional cases such as two lines on the same right-of-way next to an airport. In either case, loss of either single or multiple elements should not cause uncontrolled, widespread collapse of the interconnected power system.

3. **System contingency response.** Following the outage and before adjustments can be made:

   (a) No remaining element shall exceed its short-time emergency rating.

   (b) The steady-state system voltages shall be within emergency limits.

The limiting event shall be determined by conducting power flow and stability studies while simulating various operating conditions. These studies shall be updated as system configurations introduce significant changes in the interconnection.

Section 4 - System Coordination

A high degree of coordination is essential within and between the entities, control areas, pools and coordinated areas of the WSCC in all phases of operation which can affect the reliability of the interconnected power system.

This section sets forth operating items that require coordination to make certain that the minimum operating reliability criteria contained herein can be realized by the interconnected power system.

A. Monitoring System Conditions

Coordination and communication in the following areas is essential for secure and reliable operation of the interconnected power system.

1. **System conditions.** Loads, generation, transmission line and bulk power transformer loading, voltage, and frequency shall be monitored as required to determine if system operation is within known safe limits under both normal and emergency situations.

2. **Deviations.** The use of automatic equipment to bring immediate attention to important deviations in system operating conditions and to indicate or initiate corrective action shall be implemented.

3. **Remedial action scheme status alarms.** Alarms shall be provided to alert operating personnel regarding the status of remedial action schemes which are under their direct control and impact the reliability and security of interconnected power system operation.

4. **Sharing operational information.** All entities shall, by mutual agreement, provide essential and timely operational information regarding their system (e.g., line flows, generator status, net interchange schedules at tie points, etc.) to all affected transmission providers and control areas.

5. **Voltage collapse.** Information regarding system problems that could lead to voltage collapse shall be disseminated and operation to alleviate the effects of such severe conditions shall be coordinated.

B. Coordination with Other Entities

1. **Procedures.** Procedures shall be in place for the effective transfer of operating information between control areas, entities, and coordinated groups of entities as necessary to maintain interconnected power system reliability.

2. **Switching operation.** The opening or closing of interconnections between control areas, and the opening or closing of any lines internal to control areas which may affect the operation of the interconnected power system under normal and emergency conditions must be fully coordinated.

3. **Voltage and reactive flows.** Control areas shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions. All operating entities shall assist with their control area's coordination efforts.

4. **Load shedding and restoration.** The shedding and restoration of loads in emergencies must be coordinated as described in detail in Sections 5.D. and 6.C.

5. **Automatic actions.** Any automatic controlled islanding and automatic generator tripping which is necessary to maintain interconnected power system stability under emergency conditions shall be coordinated. All automatic remedial actions (automatic bypass of series compensation, phase shifter runback, opening of lines or transformers, load tripping, etc.) which may impact the interconnected power system, shall be coordinated.

6. **Interconnection capabilities.** Information regarding the operating capabilities of interconnecting facilities between operating entities or control areas shall be exchanged routinely and all operating entities shall coordinate establishment of the operating limitations of these facilities under normal and emergency conditions.

7. **Plans and forecasts.** Information regarding short-term load forecasts, generating capabilities, and schedules of additions or changes in system facilities that could affect interconnected operation shall be routinely disseminated.

8. **System characteristics.** Information regarding system electrical characteristics that affect the operation of the interconnected system, including any significant changes which result from the addition of facilities or modification of existing facilities, shall be routinely disseminated.

9. **Operating reserve.** Information regarding operating reserve policies and procedures shall be routinely disseminated.

10. **Abnormal operating conditions.** Operating entities forced to operate in such a way that a single contingency could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse, shall promptly notify WSCC and other affected operating entities via the WSCC Communication System.

11. **Notification of system emergencies.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WSCC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

12. **Notification of noncompliance.** If an operating entity is not able to comply with the condition and term of a particular criterion, it must notify the host control area. The control area operator will notify the WSCC who will report the noncompliance to the NERC Operating Committee.

C. Maintenance Coordination

1. **Sharing information.** The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of

generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

D. System Protection Coordination

Reliable and adequate relaying must be provided to protect and permit maximum utilization of generation, transmission and other system facilities.

1. **Coordination.** Information regarding protective relay systems affecting interconnected operation shall be routinely disseminated and the settings of such relays shall be coordinated with the affected entities.
2. **Reviewing settings.** Relay applications and settings shall be reviewed periodically and adjustments made as needed to meet system requirements.
3. **Testing.** Each operating entity shall periodically test protective relay systems and remedial action schemes which impact the security and reliability of interconnected power system operation.

Section 5 - Emergency Operations

Even though precautionary measures have been developed and utilized, and extensive protective equipment installed, emergencies of varying magnitude do occur on the interconnected power system. These emergencies may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, and interruption of customer service. All entities are expected to cooperate and take appropriate action to mitigate the severity or extent of any foreseeable system disturbance. Those operating criteria relating to emergency operation are set forth in this section.

A. Emergency Operating Philosophy

During an emergency condition, the security and reliability of the interconnected power system are threatened; therefore, immediate steps must be taken to provide relief. The following operating philosophy shall be observed:

1. **Corrective action.** The entity(ies) experiencing the emergency condition shall take immediate steps to relieve the condition by adjusting generation, changing schedules between control areas, and initiating relief measures including manual or automatic load shedding (if required) to relieve overloading or imminent voltage collapse. ACE shall be returned to zero or to its predisturbance value within the time specified in the Disturbance Control Standard following the start of a disturbance.
2. **Written authority.** Dispatching personnel shall have full responsibility and written authority to implement the emergency procedures listed in 5.A.1. above.
3. **Reestablishing reserves.** Operating entities or control areas shall immediately take steps to reestablish reserves to protect themselves and ensure that loss of

any subsequent element will not violate any operating limits. The time taken to restore resource operating reserves shall not exceed 60 minutes.

4. **Notifying other affected entities.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WSCC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

5. **AGC.** AGC shall remain in service as long as its action continues to be beneficial. If AGC is out of service, manual control shall be used to adjust generation. AGC shall be returned to service as soon as practicable.

6. **Prompt restoration.** The affected entity(ies) and control area(s) shall restore the interconnected power system to a secure and reliable state as soon as possible.

7. **Zeroing schedules.** Energy schedules on a transmission path shall be promptly reduced to zero following an outage of the path unless a backup transmission path has been pre-arranged. If a system disturbance results in system islanding, all energy schedules across open paths between islands shall be immediately reduced to zero unless doing so would prolong frequency recovery.

8. **Emergency total transfer capability limits.** Emergency total transfer capability limits shall be established which will permit maintaining stability with voltage levels, transmission line loading and equipment loading within their respective emergency limits in the event another contingency occurs.

9. **Adjustments following loss of resources.** Following the loss of a resource within a control area, scheduled and actual interchange shall be re-balanced within the time specified in the Disturbance Control Standard following the loss of a resource within a control area. Following the loss of a remote resource or curtailment of other interchange being scheduled into a control area with no backup provisions, the energy loss shall be immediately reflected in the control area's ACE and corrected within the time specified in the Disturbance Control Standard.

B. Coordination with Other Entities

1. **Emergency outages.** Information regarding emergency outages of facilities, the time frame for restoration of these facilities, and the actions taken to mitigate the effects of the outages must be exchanged promptly with other affected entities.

2. **Voltage collapse.** Information regarding problems that could lead to voltage collapse shall be disseminated to other affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

3. **Other affecting conditions.** Information regarding violent weather disturbances or other disastrous conditions which could affect the security and reliability of the interconnected power system shall be disseminated to all affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

4. **Single contingency exposure.** All affected entities shall be notified promptly via the WSCC Communication System by any entity forced to operate in such a way that a single contingency outage could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse. Entities not connected to the WSCC Communication System shall make this notification through their host control area.

5. **Emergency support personnel.** All control areas shall arrange for technical and management support personnel to be available 24 hours per day to provide coordination support in the event of system disturbances or emergency conditions. These personnel shall be on call to coordinate collecting and sharing of information. Each control area shall develop procedures in coordination with the Security Coordinators and the WSCC office to fulfill this support responsibility. The Security Coordinators shall expedite communication of appropriate information to the WSCC office during system disturbances and emergency operating conditions to enable the WSCC office to coordinate the reporting of information pertaining to the entire western region to federal agencies, regulatory bodies, and the news media in a timely manner. Management support personnel shall maintain close and timely communication with the WSCC office during extreme emergency conditions or system disturbances of widespread significance in the Western Interconnection.

C. Insufficient Generating Capacity

1. **Capacity or energy shortages**

   (a) A control area experiencing capacity or energy shortages after exhausting all possible assistance from entities within the control area shall immediately request assistance from adjacent control areas or entities. Neighboring control areas shall be notified as to the amount of the capacity or energy shortages. Neighboring control areas shall make every effort to provide all available assistance.

   (b) If inadequate relief is obtained from (a) above, then,

      (1) Procedures outlined in the *WSCC Procedure for Securing Emergency Assistance* shall be implemented.

      (2) Control area(s) shall initiate relief measures as required to maintain reserves.

2. **Deficient control area.** A control area is considered deficient when:

   - <u>all</u> available generating capacity is loaded, and
   - <u>all</u> operating reserve is utilized, and

- all interruptible load and interruptible exports have been interrupted, and
- all emergency assistance from other control areas is fully utilized, and
- the ACE is negative and cannot be returned to zero in the time specified in the Disturbance Control Standard.

In this case, it will be necessary to manually shed firm load without delay to return the ACE to zero.

3. **Manual load shedding.** Through written standing orders and instructions the system dispatchers shall be given clear authority to implement manual load shedding without consultation whenever, in their judgment, such immediate action is necessary to protect the reliability and integrity of the system. Manual load shedding may also be required to restore system frequency which has stabilized below 60 Hz or to avoid an imminent separation which would produce a severe deficiency of power supply in the affected area. Upon system separation or islanding, manual load shedding may be required to restore system frequency which has stabilized below 60 Hz.

D. Restoration

Following a major disturbance which may require load shedding, sectionalizing, or generator tripping, immediate steps must be taken to return the system to normal. Extreme care must be exercised to avoid prolonging or compounding the emergency. While each disturbance will be different and may require different dispatcher action, the criteria set forth in the following subsections will provide the general guidelines to be observed. It is imperative that dispatchers maintain close coordination with neighboring dispatchers during restoration as follows:

1. **Extent of island.** Determine the extent of the islanded area or areas. Take any necessary action to restore area frequency to normal, including adjusting generation, shedding load and synchronizing available generation with the area.

   The following is a checklist of items to be communicated to determine any action required prior to reconnecting systems following a major disturbance:

   (a) Determine the condition of your own system:

   (1) Separation points

   (2) Overloaded ties

   (3) Power flows

   (4) Condition of generation

   (5) Load shed

   (b) Contact immediate neighbors to determine their condition:

   (1) Effect of the disturbance on them.

   (2) Their separation points.

(3) Can a tie be made to them which will help your system or will help their system?

(4) The amount of their or your system to be paralleled or picked up.

(5) The relative speeds of the two systems and the potential impacts of closing the tie.

(6) Overload conditions or potential overloads to be made worse or better by the tie.

(7) The voltage difference between the two systems that must be corrected by shedding load, adjusting generation or connecting reactive equipment before the tie is closed.

(c) Determine the best tie to be made among neighbors. Proceed to make the tie as recommended in the *WSCC Interconnection Disturbance Assessment and Restoration Guidelines* in the OC Handbook.

2. **Start-up power.** Prior to restoring large customer loads, provide start-up power to generating stations and off-site power to nuclear stations where required. Adjacent entities shall establish mutual assistance arrangements for start-up power to expedite prompt restoration.

3. **Synchronizing areas.** As soon as voltage, frequency and phase angle permit, synchronize the islanded area with adjacent areas, using extreme caution to avoid unintentionally synchronizing large interconnected areas through relatively weak lines.

4. **Restoring loads.** Loads which have been shed during a disturbance shall only be restored when system conditions have recovered to the extent that those loads can be restored without adverse effect. If loads are reconnected by manual means or by supervisory control, they shall be restored only by direct action or order of the dispatcher, as generating capacity becomes available and transmission ties are reconnected. Loads shall not be manually restored until sufficient generating resources are available to return the ACE to zero within ten minutes. If automatic load restoration is used, it shall comply with the *WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* and any other more stringent local program established in thorough coordination with neighboring systems and designed to avoid the possibility of recreating underfrequency, overloading ties, burdening neighboring systems, or delaying the restoration of ties. Relays installed to restore load automatically shall be set with varying and relatively long time delays, except in those cases where automatic load restoration is designed to protect against frequency overshoot.

E. Disturbance Reporting

Information and experience gained from studying disturbances which affect the operation of the interconnected power system are helpful in developing improved operating techniques.

1. **Disturbance analysis.** Entities and coordinated groups of entities within the WSCC shall establish procedures and responsibility for collecting, analyzing and disseminating information and data concerning major disturbances. To facilitate post disturbance analyses, oscillographic and event recording equipment shall be installed at all key locations and synchronized to National Institute of Standards and Technology time.

2. **Recommendations.** Recommendations for eliminating or alleviating causes and effects of disturbances shall be made when appropriate.

F. Sabotage Reporting

Each operating entity or control area shall establish procedures for recognizing and reporting unusual occurrences suspected or determined to be acts of sabotage. These procedures shall cover recognizing acts of sabotage, disseminating information regarding such acts to the appropriate persons or entities within the area or within the interconnected power system, and notifying the appropriate local or regional law enforcement agencies.

Section 6 - Operations Planning

Each operating entity and coordinated group of operating entities is responsible for maintaining, and implementing as required, a set of current plans which are designed to evaluate options and set procedures for secure and reliable operation through a reasonable future time period. This section specifies requirements for operations planning to maintain the security and reliability of the interconnected power system.

A. Normal Operations

1. **Operating studies.** Studies conducted to obtain information which identifies operating limitations affecting transmission capability, generating capability, other equipment capability and power transfers between transmission providers or control areas shall be coordinated. To be considered acceptable, operating study results must be in compliance with the WSCC Disturbance-Performance Table within the *WSCC Reliability Criteria for Transmission System Planning*.

2. **Transfer limits under outage and abnormal system conditions.** In addition to establishing total transfer capability limits under normal system conditions, transmission providers and control areas shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3. **Joint agreement on limits.** All total transfer capability limits will be jointly agreed to by neighboring transmission providers or control areas.

B. Emergency Operations

1. **Emergency plans.** A set of plans shall be developed, maintained, and implemented as required by each operating entity or coordinated group of

operating entities to cope with operating emergencies. These plans shall be coordinated with the Security Coordinators and other entities or coordinated groups of entities as appropriate. The plans shall be reviewed at least annually to ensure that they are up to date and a copy of the plans shall be provided to the Security Coordinators and shared with other entities as appropriate.

2. **Loads requiring backup power.** A reliable, adequate and automatic backup power supply shall be provided for the control center and other critical locations to ensure continuous operation of control equipment, communication channels, metering and recording equipment and other critical equipment during loss of normal power supply. Such backup power supply shall be adequate to carry equipment through a prolonged power interruption.

C. Automatic Load Shedding and System Sectionalizing

All control areas, coordinated groups of entities, and other entities serving load, shall jointly determine potential system separation points and resulting system islands and establish a program of automatic high-speed load shedding designed to arrest frequency decay. Such a program is essential in minimizing the risk of total system collapse in the event of separation, protecting generating equipment and transmission facilities against damage, providing for equitable load shedding among entities serving load and improving overall system reliability. Such islanding and load shedding should be controlled so as to leave the islands in such condition as to permit rapid load restoration and reestablishment of interconnections.

1. **WSCC regional coordination.** As new transmission facilities are constructed and study results and/or actual operating experience indicate differing islanding patterns, individual area load shedding programs shall be altered or integrated into other area programs to maintain an overall coordination of load shedding programs within the WSCC.

   A coordinated load shedding program shall be implemented to shed the necessary amount of load in each island area to arrest frequency decay, minimize loss of load and permit timely system restoration. Such island areas shall devise load shedding plans in accordance with the criteria outlined in the subsections that follow. As part of its participation in a coordinated load shedding program with neighboring entities, each entity serving load shall be equipped to automatically shed load at separate frequency levels over an appropriate frequency range. The load shedding shall be matched to the island area needs and coordinated within the island area.

2. **Underfrequency relays.** All automatic underfrequency load shedding comprising a coordinated load shedding program shall be accomplished by use of <u>solid-state underfrequency relays</u>. Electro-mechanical relays shall not be used as part of any coordinated load shedding program. In each island area, all relay settings shall be coordinated and based on the characteristics of that island area. It is essential that the underfrequency load shedding relay settings are coordinated with underfrequency protection of generating units and any other manual or automatic actions which can be expected to occur under conditions of frequency decline.

3. **Technical studies.** The coordinated automatic load shedding program shall be based on studies of system dynamic performance, under conditions which would cause the greatest potential imbalance between load and generation, and shall use the latest state-of-the-art computer analytical techniques. The studies shall be able to predict voltage and power transients at a widespread number of locations, as well as the rate of frequency decline, and shall reflect the operation of underfrequency sensing devices.

4. **Load shedding steps.** Automatic high-speed load shedding shall comply with the *WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* so as to minimize the risk of further separation, loss of generation, excessive load shedding accompanied by excessive overfrequency conditions, and system shutdown.

5. **Generators isolated to local load.** Where practical, generators shall be isolated with local load to minimize loss of generation and enable timely system restoration in situations where the load shedding program has failed to arrest frequency decline.

6. **Separation.** The opening of intra-area and inter-area transmission interconnections by underfrequency relaying shall only be initiated after the coordinated load shedding program has failed to arrest frequency decline and intolerable system conditions exist.

7. **Voltage reduction.** If voltage reduction is utilized for manual load relief, such reduction shall not be made to the high voltage transmission system.

8. **Protection from high frequency.** In cases where area isolation with a large surplus of generation in relation to load requirements can be anticipated, automatic generator tripping or other remedial measures shall be used to prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage.

D. System Restoration

1. **Restoration plan.** Each transmission provider and control area shall have an up-to-date restoration plan and provide personnel training and telecommunication facilities needed to implement the restoration plan following a system emergency. Entities and coordinated groups of entities shall coordinate their restoration plans with other affected entities or coordinated groups of entities. All restoration plans shall be reviewed a minimum of every three years.

2. **Synchronizing.** To the extent possible, synchronizing locations shall be determined ahead of time and dispatchers shall be provided appropriate procedures for synchronizing. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect resynchronization.

E. Control Center Backup

Each control area shall have a plan to provide continued operation in the event its control center becomes inoperable. For interconnected operations, the goal of this plan is to avoid placing a prolonged burden on neighboring control areas during a control center outage. Since most control centers differ in their internal functions and responsibilities, each control area should decide which specific functions, other than the basic functions shown below, will be necessary to continue their operations from an alternate location. These criteria do not obligate control areas to provide complete and redundant backup control facilities, but to provide essential backup capability. Each control area may, as an option, make appropriate arrangements with another control area to provide the minimum backup control functions in the event its primary control functions are interrupted. As part of its plan the control area is expected to comply with the following requirements (through automatic or manual means) as a minimum:

1. **Notification.** Provide prompt notification, which should include any necessary pertinent information, to other control areas in the event that primary control center functions are interrupted.
2. **Communications.** Maintain basic voice communication capabilities with other control areas.
3. **Schedules.** Maintain the status of all interarea schedules such that there is an hourly accounting of all schedules.
4. **Critical interconnections.** Know the status of and be able to control all critical interconnection facilities.
5. **Tie line control.** Provide basic tie line control capability to avoid burdening neighboring control areas with excessive inadvertent interchange.
6. **Periodic tests.** Conduct periodic tests of backup and control functions to ensure they are in working order.
7. **Procedures and training.** Provide adequate written procedures and training to ensure that operating personnel are able to implement all backup control functions when required.

Section 7 - Telecommunications

For a high degree of service reliability under normal and emergency operation, it is essential that all entities have adequate and reliable telecommunication facilities.

A. Facilities

1. **Between control centers.** At least one main telecommunication channel with an alternate backup channel shall be provided between control centers of adjacent interconnected control areas, between control centers and key stations within a control area, and between other control areas as required.
2. **Alternate facilities.** Alternate facilities shall be provided to protect against interruption of essential telemetering, control and relaying telecommunications.

3. **Standby power supply.** Telecommunication facilities shall be provided with an automatic standby emergency power supply adequate to supply requirements for a prolonged interruption.

B. WSCC Communication System

Control area control centers shall be connected to the WSCC Communication System either directly or via pool communication facilities and the terminals shall be readily available to the dispatchers. Other transmission providers are encouraged to be connected to the WSCC Communication System.

C. Loss of Telecommunications

Each control area shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunication facilities.

Section 8 - Operating Personnel and Training

A. Responsibility and Authority

1. **Written authority.** Each system operator shall be delegated sufficient authority in writing to take any action necessary to ensure that the system or control area for which the operator is responsible is operated in a stable and reliable manner.

B. Requirements

1. **Dispatchers/System Operators and plant operators.** Dispatchers/System Operators and plant operators shall be qualified, trained and thoroughly indoctrinated in the principles and procedures of interconnected power system operation.
2. **Other personnel.** Other personnel involved in system operations, including, but not limited to, schedulers, contract writers, marketers, and energy accountants, shall be thoroughly familiar with the procedures and principles of interconnected power system operation which pertain to their job function.

C. Training

1. **Regular training.** Training shall be conducted regularly to keep all operating personnel involved in the operation of the interconnected power system abreast of changing conditions and equipment on their own system and on other interconnected systems. WSCC Members and other entities are encouraged to use the WSCC Training Program as a supplement to their internal training programs.
2. **Contingency analysis.** System operating personnel shall be kept informed through appropriate power flow and stability studies of the effect that failure or loss of various system components has upon the reliability of their control area and the interconnected systems.

D. Certification.

Statement of intent: Certification is intended to apply to those Dispatchers/System Operators in a position to make and/or carry out decisions, without review by higher authority, that impact interconnected system reliability. "Higher authority" means entities such as Control Areas, ISOs, and Security Coordinators.

Personnel who must be certified:

Exception. *Any organization required to have WSCC-Certified Dispatchers/System Operators shall have a period not to exceed three years from the time it employs a new Dispatcher/System Operator or a new trainee in the Dispatcher/System Operator position to ensure the new employee attains WSCC Certification. For at least the first of those three years, the uncertified Dispatcher/System Operator shall work only in a non-independent position with a WSCC-Certified Dispatcher/System Operator.*

Operating Authority Definition. Control Areas and Independent System Operators are considered Operating Authorities.

Administration. The WSCC Dispatcher/System Operator Certification examination will be administered on a pre-scheduled periodic basis at sites in the western United States and Canada.

E. Information Sharing

1. **Information requirements.** Each operating entity's personnel shall respond to the information requirements of other operating entities, coordinated groups of operating entities, and the WSCC Operations Committee.

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WESTERN SYSTEMS COORDINATING COUNCIL

DEFINITIONS

PART IV

WESTERN SYSTEMS COORDINATING COUNCIL

RELIABILITY CRITERIA FOR TRANSMISSION SYSTEM PLANNING
AND
MINIMUM OPERATING RELIABILITY CRITERIA

DEFINITIONS

Adequacy

The ability of a bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Adjustment

Manual or automatic action following a disturbance. These actions are taken to prevent unacceptable system performance should a subsequent disturbance occur prior to system restoration.

Angular Stability

Angular positions of rotors of synchronous machines relative to each other remain constant (synchronized) when no disturbance is present or become constant (synchronized) following a disturbance. If the interconnected transmission system changes too much or too suddenly, some synchronous machines may lose synchronism resulting in a condition of angular instability.

Anti-Aliasing Filter

An analog filter installed at a metering point to remove aliasing errors from the data acquisition process. The filter is designed to remove the high frequency components of the signal over the AGC sample period.

Area Control Error (ACE)

The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent interchange if automatic correction for either is part of the system's AGC).

Automatic Generation Control (AGC)

Equipment which automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

Automatic Voltage Control Equipment

Equipment which controls the output of reactive power resources based on local system voltage or loads.

Black-Start Capability

The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Blackout

The disconnection of all electrical sources from all electrical loads in a specific geographical area. The cause of disconnection can be either a forced or a planned outage.

Bulk Power Transformers

Transformers which are connected in parallel with other elements of the bulk transmission network and therefore influence the loading and reliability of those other elements. A transformer which connects a radial load is not generally considered a bulk power transformer. Large generation step-up transformers are sometimes considered to be bulk power transformers.

Cascading

Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location which results in widespread service interruption.

Contingency

Single Contingency - The loss of a single system element under any operating condition or anticipated mode of operation.

Most Severe Single Contingency - That single contingency which results in the most adverse system performance under any operating condition or anticipated mode of operation.

Multiple Contingency Outages - The loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short (less than ten minutes) to permit system adjustment in response to any of the losses.

Control Area

An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection.

<u>Controlled Action</u>

The switching of system elements as the planned response to system events or system conditions. For example, underfrequency and undervoltage load tripping are considered inherently controlled actions because the actions are the planned response to specific conditions on the system at the load locations. Out-of-step tripping of a line is considered an inherently controlled action because the action is the planned response to a specific condition on the line.

Random line tripping caused by protective relay action in response to a non-fault condition such as a system swing is generally considered an uncontrolled action because this action is not the normal response intended for the protective relay.

<u>Controlled Islanding</u>

The controlled tripping of transmission system elements in response to system disturbance conditions to form electrically isolated islands which are relatively balanced in their composition of load and generation. This controlled action is taken to prevent cascading, minimize loss of load, and enable timely restoration.

<u>Credible</u>

That which merits consideration in operating and planning the interconnected bulk electric system to meet reliability criteria.

<u>Critical Generating Unit</u>

A unit that is required for the purpose of system restoration.

<u>Disturbance</u>

An unplanned event which produces an abnormal system condition such as high or low frequency, abnormal voltage, or oscillations in the system.

<u>Embedded System</u>

The integrated electrical generation and transmission facilities owned or controlled by one organization that are integrated in their entirety within the facilities owned or controlled by another single system.

<u>Emergency</u>

Any abnormal system condition which requires immediate manual or automatic action to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of the electric system.

<u>Emergency Limit</u>

The loading of a system element in amperes or MVA or the voltage level permitted by the owner of the element for a maximum duration of time such as thirty minutes or other similar short period.

Entity

A participant who is involved in the transmission, distribution, generation, scheduling, or marketing of electrical energy. Participants include, but are not limited to utilities, transmission providers, independent power producers, brokers, marketers, independent system operators, local distribution companies, and control area operators.

Frequency Bias

A value, usually given as MW/0.1 Hz, associated with a control area which relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Governor Droop

Governor droop is the decrease in frequency to which a governor responds by causing a generator to go from no load to full load. This definition of governor response is more precisely defined as "speed regulation" which is expressed as a percent of normal system frequency. For instance, if frequency decays from 60 to 57 hertz, a 5% change, a hydro generator at zero load with a governor set at a 5% droop would respond by going to full load. For smaller changes in frequency, changes in generator output are proportional. The more technically correct definition of governor droop is the change in frequency to which a governor responds by causing turbine gate position to move through its full range of travel, which is generally non-linear and a function of load.

Inadvertent Interchange

The difference between the control area's net actual interchange and net scheduled interchange.

Independent Power Producer

A producer of electrical capacity and energy which owns the generation asset, but does not typically own any transmission or distribution assets. Also known as a Non-Utility Generator (NUG).

Interconnected Power System

A network of subsystems of generators, transmission lines, transformers, switching stations, and substations.

Interruptible Imports, Exports and Loads

Those imports, exports and loads which by contract can be interrupted at the discretion of the supplying system.

Island

A portion of the interconnected system which has become isolated due to the tripping of transmission system elements.

Load Responsibility

A control area's firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier.

Local Network

A Local Network (LN) is a non-radial portion of a system and has been planned such that a disturbance may result in loss of all load and generation in the LN.

1. The LN is not a control area.
2. The loss of the LN should not cause a Reliability Criteria violation external to the LN.

Natural Frequency Response Characteristic

Also called the "Natural Combined Characteristic" is the manner in which a system's generation and load would respond to a change in system frequency in the absence of AGC. In practice, system regulation is achieved by the combined effects of generation governing and load governing.

Planning Margin

The transmission capability remaining in the system to accommodate unanticipated events. It can be embedded in conservative modeling and system representation assumptions (built-in margin), and can be explicitly established as well with operating limits and facility ratings. Some of the more important margins are related to current overloads, transient stability performance, oscillatory damping, post-transient voltage, and reactive support. If systems are modeled accurately, simulation results will provide an accurate relationship to the selected margin criteria. Simulations using built-in margins (conservative simplifications) produce an inaccurate sense of what the actual margins are.

Radial System

A radial system is connected to the interconnected transmission system by one transmission path to a single location. For the purpose of application of this Reliability Criteria,

1. A control area is not a radial system.
2. The loss of the radial system shall not cause a Reliability Criteria violation external to the radial system.

Reactive Reserves

The capability of power system components to supply or absorb additional reactive power in response to system contingencies or other changes in system conditions. Reactive reserves may include additional reactive capability of generating units, and other synchronous machines, switchable shunt reactive devices, automatic fast acting devices such as SVCs, and other power system components with reactive power capability.

Regulating Margin

The amount of spinning reserve required under non-emergency conditions by each control area to bring the area control error to zero at least once every ten minutes and to hold the average difference over each ten-minute period to less than that control area's allowable limit for average deviation as defined by the NERC control performance criteria.

Reliability

The combination of Security and Adequacy, as defined in this section.

Remedial Action

Special preplanned corrective measures which are initiated following a disturbance to provide for acceptable system performance. Typical automatic remedial actions include generator tripping or equivalent reduction of energy input to the system, controlled tripping of interruptible load, DC line ramping, insertion of braking resistors, insertion of series capacitors and controlled opening of interconnections and/or other lines including system islanding. Typical manual remedial actions include manual tripping of load, tripping of generation, etc.

Remedial Action Scheme

A protection system which automatically initiates one or more remedial actions. Also called Special Protection System.

Reserve

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning reserve and nonspinning reserve.

Spinning Reserve - Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve - An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve - An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Nonspinning Reserve - That operating reserve not connected to the system but capable of serving demand within ten minutes, or interruptible load that can be removed from the system within ten minutes.

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits, unanticipated loss of system components or switching operations.

Simultaneous Outage

Multiple outages are considered to be simultaneous if the outages subsequent to the first event occur before manual system adjustment can be made. For simulation purposes, it may be assumed that the outages occur at the same instant, or the outages may be staggered if the time sequence is known.

System

The integrated electrical facilities, which may include generation, transmission and distribution facilities, that are controlled by one organization.

System Adjusted

System Adjusted means the completion of manual or automatic actions, acknowledging the outage condition, to improve system reliability and prepare for the next disturbance; i.e., change in generation schedules, tie line schedules, or voltage schedules. System Adjusted does not include automatic control action to maintain prefault conditions such as governor action, economic dispatch and tie line control, excitation system action, etc.

Total Transfer Capability (TTC)

The amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting *all* of a specific set of defined pre- and post-contingency system conditions.

Uncontrolled

The unanticipated switching of system elements at locations and in a sequence which have not been planned.

Unscheduled Flow

The difference between the scheduled and actual power flow, on a transmission path.

Voltage Collapse

A power system at a given operating state and subject to a given disturbance undergoes voltage collapse if post-disturbance equilibrium voltages are below acceptable limits. Voltage collapse may be total (blackout) or partial and is associated with voltage instability and/or angular instability.

Voltage Instability

A system state in which an increase in load, disturbance, or system change causes voltage to decay quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse.

Western Interconnection

The interconnected electrical systems that encompass the region of the Western Systems Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.

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WESTERN SYSTEMS COORDINATING COUNCIL

PROCESS FOR DEVELOPING AND APPROVING WSCC STANDARDS

PART V

PROCESS FOR DEVELOPING AND APPROVING
WSCC STANDARDS

Approved by WSCC Board of Trustees – August 24, 1999

Introduction

This document explains the process that WSCC has established for announcing, developing, revising, and approving WSCC Standards. WSCC Standards include WSCC Operating and Planning Policies, Procedures, and Criteria, and their associated measurements for determining compliance. The process involves several steps:

- Public notification of intent to develop a new Standard, or revise an existing Standard.
- Subcommittee drafting stage.
- Posting of draft for public comment.
- Subcommittee review of all comments and public posting of decisions reached on each comment.
- WSCC Operations Committee or Planning Coordination Committee approval of proposed Standard based on its technical appeals.
- Appeals Committee resolution of any "due process" or "technical" appeals.
- WSCC Board of Trustees (Board) approval of proposed Standard.

The process for developing and approving WSCC Standards is generally based on the Standard-making procedures used by the American National Standards Institute (ANSI), the Institute of Electrical and Electronics Engineers (IEEE), and the American Society of Mechanical Engineers (ASME):

1. Notification of pending Standard change before a wide audience of all "interested and affected parties,"
2. Posting Standard change drafts for all parties to review,
3. Provision for gathering and posting comments from all parties,
4. Provision for an appeals process – both "due process" and "technical" appeals.

The issues of compliance and enforcement of the WSCC Standards are currently being developed through the WSCC Reliability Management System (RMS). In cases requiring expediency, such as in the development of emergency operating procedures, a new or modified Standard may be approved by the Operations Committee or Planning Coordination Committee. Any such Standard must have an associated termination date and, even though already implemented, must undergo the formal technical review and approval process. Should this Standard not be formally approved through WSCC's Standards development and approval process it will cease to be in effect upon conclusion of the process.

Terms

Standards Committee. The Operations Committee (OC) or Planning Coordination Committee (PCC)[1]. OC and PCC will coordinate their responsibilities for those Standards that have both operating and planning implications.

Subgroup. A subcommittee, work group, or task force of the OC, PCC, or both; usually where WSCC Standards are drafted and posted for review[2].

Due Process Appeals Committee. The committee that receives comments from those who believe that the "due process" procedure was not properly followed during the development of a Standard. The Due Process Appeals Committee consists of three Board representatives selected by the Board Executive Committee. Not more than one Board representative of the electric industry sectors (Major Transmission Utility, Transmission Dependent Utility, Independent Power Producer/Marketer), Canada, Mexico, and regulatory observer representatives may serve at the same time on the Due Process Appeals Committee. To preserve continuity, the membership terms of the three Appeals Committee representatives will be staggered. The WSCC Assistant Executive Director shall be the staff coordinator for the Due Process Appeals Committee. Decisions of the Appeals Committee will be based upon a majority vote of those members eligible to vote[3].

Technical Appeals Committee. The committee that receives comments from those who believe that their "technical" comments were not properly addressed during the development of a Standard. The Technical Appeals Committee consists of the vice chairs of the Operations Committee, Planning Coordination Committee, and Board. The WSCC Assistant Executive Director shall be the staff coordinator for the Technical Appeals Committee. The Technical Appeals Committee will make assignments as necessary to existing WSCC technical work groups and task forces, form new technical groups if necessary, and utilize other technical resources as required to address technical appeals. Decisions of the Technical Appeals Committee will be based upon a majority vote of those members eligible to vote[3].

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[1] Membership in WSCC's Planning Coordination Committee and Operations Committee is in accordance with WSCC's *Agreement and Bylaws*.

[2] Formation of Subgroups is in accordance with the Planning Coordination Committee's and Operations Committee's *Organizational Guidelines*.

[3] The eligibility to vote is as prescribed in WSCC's *Agreement and Bylaws*.

Steps

Step 1 – Request To Revise or Develop a Standard

Requests to revise or develop a Standard are submitted to the Board of Trustees (Board), or to the Standards Committee (WSCC OC or PCC). Requests submitted to the Board will be assigned to PCC or OC, as appropriate, on a case by case basis. Requests submitted to either PCC or OC directly will be evaluated by these respective committees to determine which committee should address the requests. In some instances a joint involvement will be needed to address requests that are applicable to both planning and operating Standards. Changes to the WSCC Standards may be offered by any individual or organization with a legitimate interest in electric system reliability, such as:

- Transmission owners
- Generation owners
- Independent System Operators (ISOs)
- Transmission dependent utilities
- Independent power producers
- Power marketers
- Customers, either retail or wholesale for resale
- State agencies concerned with electric system reliability
- WSCC subgroups
- Electric industry organizations

A request to revise or develop a Standard must include an explanation of the need for a new or revised Standard and be accompanied by a preliminary technical assessment performed by, or prepared under the direction of, the entity(ies) supporting the request.

Step 2 – Assignment to Subgroup

The Board or Standards Committee then assigns the request to whichever Subgroup(s) are responsible for those issues. If a proposed new Standard or revision to an existing Standard has implications for both planning and operations, the Subgroup will include a composite of individuals having the appropriate planning and operations expertise. Notification of such assignments will be posted on the WSCC Web site and sent to all parties that subscribe to the WSCC Standards e-mail list server. Interested parties may express their interest in participating in the deliberations of the Subgroup. The Subgroup membership will be administered in accordance with the WSCC *Guidelines for Administering the Membership of WSCC Subcommittees, Work Groups and Task Forces*.

Step 3 – Subgroup Begins Drafting Phase and Announces on Internet

The Subgroup will begin working on the new or revised request no later than at its next scheduled or special meeting. A minimum of 30 days notice will be provided prior to all Subgroup meetings in which new or revised Standards will be developed. Notification of such meetings will be posted on the WSCC Web site and sent to all parties that subscribe to the WSCC Standards e-mail list server. These meetings will be open to stakeholders having a legitimate interest in electric system reliability. The Subgroup Chair will allow some opportunity for outside comment and participation as the discussion progresses. However, the Subgroup Chair will not allow the discussion to interfere with productive discussions by the Subgroup members.

The Subgroup will review the preliminary technical assessment provided by the requester and may perform or request additional technical studies if considered necessary. The Subgroup will complete an impact assessment report as part of its evaluation to assess the potential effects of the requested Standards change. The Subgroup may request from the Board or Standards Committee additional time to study the proposed new or revised Standard if the Subgroup believes it necessary to fully assess the proposed change. If the Subgroup determines that a new Standard or change in an existing Standard is needed, it announces the pending change, provides a summary of the changes it expects to draft, and provides an explanation as to why the new Standard or change in an existing Standard is needed. The announcement and the impact assessment report will be posted on the WSCC Web site and sent to all parties that subscribe to the WSCC Standards e-mail list server. If the Subgroup determines that a new or revised Standard is not needed, it prepares and posts the response to the party that submitted the proposal with a copy to the PCC, OC, or Board, as appropriate.

Step 4 – Draft Standard Posted for Comment

The Subgroup will post its first draft of the new or revised Standard on the Internet and provide 60 days for comments. The draft must include specific measurements for determining compliance and the estimated costs of compliance. Comments on the draft will be solicited from the WSCC members and all individuals who subscribe to the WSCC Standards e-mail list server. Members of electric industry organizations may respond through their organizations, or directly, or both. All comments should be supplied electronically. WSCC will then post all comments it receives on the Internet.

Step 5 – Subgroup Deliberates on Comments

Based on the comments it receives, plus its own review, the Subgroup will revise the draft Standard as needed. It will document its disposition on all comments received, and post its decisions on the Internet along with its second draft for either further industry review or Standards Committee vote. If the Subgroup believes the technical comments are significant, it will repeat Steps 3 and 4, before sending a revised draft to the Standards Committee. Steps 3 and 4 will be repeated as many times as considered necessary by the subgroup to ensure an adequate review from a "technical" perspective. The number of days for comment on each new draft of a proposed new or revised Standard will be 60 days, similar to the review period on the initial draft of the Standard. Parties who have their technical comments on a proposed Standard rejected by a Subgroup may write to the Standards Committee for further consideration of their comments.

A majority vote of the Subgroup is required to approve submitting the recommended Standard to the Standards Committee for a vote. The vote may be by mail, conference call and/or e-mail ballot.

Step 6 – Subgroup Submits Draft for Standards Committee Vote

The Subgroup's final draft Standard is posted on the Internet and sent to the Standards Committee for a vote. The posting will include all comments that were not incorporated into the draft Standard and the date of the expected Standards Committee's vote. The posting will also be sent to the Standards e-mail list server with attachments. Proposed Standards will be posted no less than 30 days prior to the Standards Committee vote.

Standards may be voted on in their entirety or by individual provisions. The Subgroup will determine how each Standard will be addressed for vote. The Subgroup will also recommend the subdivisions to be addressed and voted on as individual provisions. To be considered by the Standards Committee, any "no" votes, by Subgroup members, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable.

Step 7 – Standards Committee Votes on Recommendation to Board

The Standards Committee will vote on the draft Standard no later than at its next scheduled or special meeting. A minimum of 30 days notice will be provided prior to all Standards Committee meetings in which new or revised Standards will be considered for approval. Notification of such meetings will be posted on the WSCC Web site and sent to all parties that subscribe to the WSCC Standards e-mail list server. These meetings will be open to stakeholders having a legitimate interest in electric system reliability. The Standards Committee Chair will allow some opportunity for outside comment and participation as the discussion progresses. However, the Standards Committee Chair will not allow the discussion to interfere with productive discussions by the Standards Committee members. If the Standards Committee approves the Standard, it sends its recommendation, the draft Standard, and any comments on which the Standards Committee did not agree, plus Standards Committee minority opinions, to the Board for final approval. To be considered by the Board, any "no" votes, by members of the Standards Committee, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable.

Proposed Standards will be posted no less than 30 days prior to the Board vote. The date of the expected Board vote shall also be posted. The Standards Committee may amend or modify a proposed Standard. The reasons for the modification(s) shall be documented, posted, and provided to the Board. Any parties that object to the modifications may appeal to the appropriate Appeals Committee. These items shall all be posted on the Internet for general review. If the Standards Committee does not approve the Standard, it may return the draft to the Subgroup for further work or it may terminate the Standard development activity with the posting of an appropriate notice to the Standards originator, the Subgroup, and the Board (if appropriate).

A majority vote of the Standards Committee is required to approve submitting the recommended Standard to the Board for a vote. The vote may be by mail, and/or e-mail ballot.

Step 8 – Appeals Process

After approval and posting by the Standards Committee, any due process or technical appeals are due, in writing, to the respective Due Process Appeals Committee or Technical Appeals Committee within 15 days. If an Appeals Committee accepts the appellant’s complaint, it rejects the draft Standard and refers the complaint to the Standards Committee or Board for further consideration. If an Appeals Committee denies the complaint, it approves the Standard for referral to the Board. Deliberations of the Appeals Committees shall not exceed 15 days.

Step 9 – Board Approval

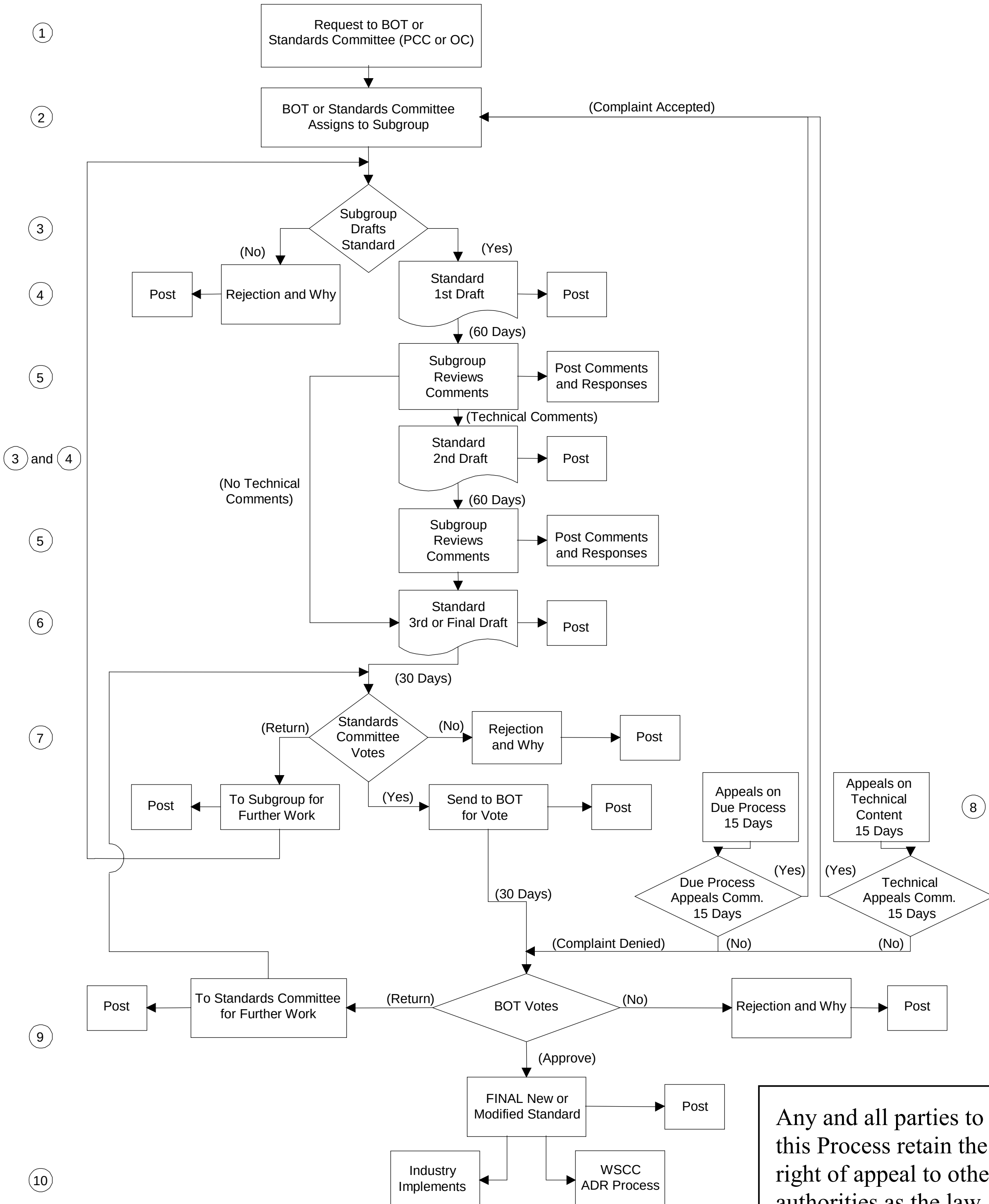
The Board will vote on the proposed Standard no later than at its next scheduled or special meeting. It will consider the Standards Committee’s recommendations and minority opinions, all comments that were not incorporated into the draft Standard, and inputs from the Due Process and Technical Appeals Committees. To preserve the integrity of the due process Standards development procedure, the Board may not amend or modify a proposed Standard. If approved, the Standard is posted on the Internet and all parties notified. If the Standard is not approved, the Board may return the Standard to the Standards Committee for further work or it may terminate the Standard activity with an appropriate notice to the Standard originator and Standards Committee. These Board actions will also be posted.

A two-thirds majority vote of the Board is required to approve the recommended Standard. The vote may be by mail, conference call and/or e-mail ballot.

Step 10 – Standard Implementation or Further Appeals

Once a new or modified Standard is approved by the Board, all industry participants are expected to implement and abide by the Standard in accordance with accepted WSCC compliance procedures. Should a party continue to object to the new or modified Standard, that party may request, either through its WSCC member, electric industry organization, or directly, to have the Board consider using WSCC's alternative dispute resolution procedure to address its objections. Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

Process for Developing and Approving WSCC Standards



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